Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER LYNCH (Mailed 3/7/2003)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation Into Implementation of Assembly Bill 970 Regarding the Identification of Electric Transmission and Distribution Constraints, Actions to Resolve Those Constraints, and Related Matters Affecting the Reliability of Electric Supply.	Investigation 00-11-001 (Filed November 2, 2000)
Conditional Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Los Banos-Gates 500 kV Transmission Project.	Application 01-04-012 (Filed April 13, 2001)

(See Attachment 1 for List of Appearances.)

TABLE OF CONTENTS

Title **Page**

LIST OF ATTACHMENTS

LIST OF TABLES AND FIGURES

INTERIM OPINION: ECONOMIC BENEFITS OF PATH 15

1. Introduction and Summary[1]

In this decision, we address benefits to ratepayers of constructing transmission improvements along the Path 15 corridor. Based on the record in this proceeding, it is clear that the Path 15 upgrades are not necessary to improve system reliability. There was no disagreement among parties on this conclusion. All parties agree that the existing capacity of Path 15 (3950 MWs) meets system reliability criteria, as defined by the Western Systems Coordinating Council and the North American Electric Reliability Council. Therefore, increasing the line capacity to approximately 5400 MWs is not needed for system reliability purposes. The issues we address today relate to the *economic need* for the project, i.e., whether adding 1500 MWs of capacity to the path produces cost savings to ratepayers that more than offset the project costs.

There was significant dispute among parties as to whether the Path 15 improvements would provide economic benefits (i.e., cost savings) to customers. Pacific Gas and Electric Company (PG&E) and the ISO assert that in circumstances where generation levels are low, such as poor hydroelectric conditions, or where market gaming is occurring, the economic benefits of improving Path 15 are significant. The Office of Ratepayer Advocates (ORA) disputes these assertions and argues that there are other options for dealing with market power problems that are less costly than upgrading Path 15. In fact, as ORA points out, four out of ten of the ISO's analyses show that in normal

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[1] Attachment 2 explains each acronym or other abbreviation that appears in this decision.

conditions, the Path 15 upgrades will cause an increase, not a decrease energy costs.

We conclude today that Path 15 improvements are not warranted to improve system reliability. This is the consensus view of all parties in this proceeding. However, we find that Path 15 may provide, under certain circumstances, economic benefits to ratepayers, in particular as an insurance policy (albeit an expensive one) against market gaming abuses such as those that occurred in 2000 and 2001. We reach this conclusion based on the uncertainty that the ISO and the Federal Energy Regulatory Commission (FERC), which regulates wholesale electric transactions, have or will institute sufficient safeguards to prevent a reoccurrence of the problems which plagued California in 2000 and 2001. Therefore, we approve PG&E's request to upgrade the Path 15 transmission system.

Path 15 is the major transmission interface between northern and southern California. (See Figure 1.) During the latter part of 2000 and early 2001, congestion occurred on Path 15 on a regular basis. Although it was the middle of winter when demand was low, generation resources proved to be scarce. The ISO was forced to regularly call a stage three emergency, which is defined as the point where operating reserves are so low that rolling blackouts are imminent. California experienced two days of rotating outages of firm customer load and numerous days of threatened outages. On February 13, 2001, the Commission's Energy Division issued a report on transmission constraints in California and their impacts on system reliability and electric prices.[2] In that report, the Energy

[2] "Relieving Transmission Constraints" prepared by Energy Division, February 13, 2001, which is appended to Decision (D.) 01-03-077.

Division identified constraints on Path 15 between southern and northern California as a major factor affecting system reliability and resulting in unnecessarily high electric prices. In response to this report, on March 29, President Lynch issued an Assigned Commissioner's Ruling in the Transmission Investigation (I.) 00-11-01 that stated, in part:

> "Over this past year, it has become increasingly clear that constraints on the transmission of power between northern and southern California have compromised electric reliability and the ability to dispatch lowest cost power. The Energy Division's report on transmission constraints identified constraints on [PG&E's] Path 15 that contributed most to 'major reliability problems in the past year' and 'likely to continue to cause problems in 2002'…. Further, that while new generation resources may have an impact on the cost-effectiveness of transmission system upgrades, the volatility of wholesale electricity markets suggests that relieving constraints on major transmission paths is an economic insurance policy (id., p. 12.)… Therefore, it is necessary for the Commission to pursue relieving the constraints on Path 15 now to ensure electric service reliability and lowest cost dispatch."[3]

Although the Commission's concerns over congestion on Path 15 during 2000 and 2001 were expressed in terms of "system reliability" problems, it became clear during the course of this proceeding that Path 15 upgrades are not needed to meet the reliability criteria as defined by the ISO, the Western Systems Coordinating Council and the North American Electric Reliability Council. The ISO testified that the project is not required for reliability purposes, and that it does not plan to conduct any further reliability studies regarding Path 15.[4]

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[3] Assigned Commissioner's Ruling Regarding Path 15 Transmission Constraints, March 29, 2001, pp. 1-2.

[4] Reporter's Transcript (RT), Vol. 6, p. 538, 576, 589.

While the ISO's testimony appears to run counter to the conventional wisdom regarding Path 15 -- and counter to the factual assumptions underlying the Assigned Commissioner's Ruling that commenced this proceeding -- it was not contradicted by any party. Conventional wisdom must give way when it is contradicted by sworn testimony of the responsible party, subject to the rigors of public scrutiny and cross-examination by knowledgeable experts. Therefore, we conclude that this project is not needed for reliability and focus on the economic need for the project.

By today's decision, we consider the economic benefits to ratepayers of adding 1500 megawatts (MW) of capacity to Path 15. More specifically, we examine the economics of the project on a "stand-alone" basis, i.e., without considering the manner in which PG&E and other entities will participate in the project.[5] In doing so, we have carefully evaluated the assumptions and methodology underlying the ISO's economic analysis in this proceeding. Based on our review, we conclude that the proposed upgrades are not cost-effective to ratepayers under normal circumstances. Our conclusion is based on the assumption that Path 15 upgrades will cost $323 million (or approximately $50 million per year on an annualized basis). However, we find that the project is valuable to customers as a means of reducing the potential impact of market abuses in the future, both via the physical benefits of the project and as a signal to market players that California will take all actions necessary to prevent a repeat of the blackouts and horrific price increases that occurred in 2000 and 2001 due to

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[5] PG&E is the entity which will receive the certificate issued pursuant to this order. See below for a discussion of the requirement that any private entity that owns or controls, directly or indirectly, the facilities authorized by this order be a utility subject to the Commission's jurisdiction.

market manipulation. It should also reduce the potential for market participants to engage in the creation of false congestion, using the "Death Star" and other strategies used by Enron and others in the past.

As explained in today's decision, the ISO conducted two studies of the Path 15 upgrades in this proceeding. They differ substantially with respect to the estimated values of market clearing prices in 2005, particularly during hours of congestion over Path 15. In the first study, the ISO examined the economics of the upgrades assuming a competitive wholesale electric market in 2005 and beyond. Under this assumption, suppliers bidding in the market are unable to establish market prices above the marginal costs of production. During hours of congestion over Path 15, market clearing prices in northern California reflect the higher costs of less efficient resources that need to be dispatched from locations other than southern California. By reducing congestion in the south-north direction, the Path 15 upgrade reduces the market price for power flowing in that direction. However, the analysis indicates that these benefits are very small relative to project costs in all but two scenarios that assume one-in-ten year drought conditions and that low levels of new generation are built in northern California and in the Pacific Northwest.

In the second study, the ISO assumed that the market power abuses experienced in 2000 would continue unabated in 2005 and beyond, resulting in market prices that reflect very large price-cost mark-ups, particularly during the hours of congestion over Path 15. As a result, the ISO's estimate of the economic value of reducing congestion over Path 15 in the second study is dramatically higher than in the first. Based on the results of this study, the ISO concludes that the project would pay for itself in one drought year and three normal years.

As discussed in this decision, we find that the ISO's second study is questionable, for several reasons. First, the ISO fundamentally errs in its market power assessment by putting arguably the most expensive fix—construction of a $323 million transmission project—as the *first* step in mitigating the market abuses experienced in 2000. This sequence results in inflated project benefits because those benefits are measured when market power is at its maximum. It presumes that regulators will fail to take any other action to address market power abuses or transmission congestion in the future *and* ignores the initiatives that have been put in place by this Commission and other agencies since 2000 to address these issues, such as forward contracting, demand-responsiveness programs, and incentives for distributed generation.

Second, the ISO's approach to estimating the impact of market power on prices omits an important modeling parameter that further biases the results of its market power study in favor of project construction. The omission affects the ISO's calculation of market concentration in 2005, which is then used as a predictor of market prices in 2005 in a regression analysis. The upward bias in the model is further substantiated by a comparison of estimated and actual price-cost markups in 2001 prepared at the direction of assigned Administrative Law Judge (ALJ). (See Figures 2 and 3.) As discussed in this decision, the predictive weakness of the model is also consistent with our observation that the ISO's regression analysis does not meet standards of statistical validation in six months out of the year.

Third, of the 24 scenarios conducted under the market power study, we find that 12 scenarios are simply implausible. These twelve assume that *all* load will be met in 2005 and beyond through spot market transactions exposed to price-cost markups, i.e., none of the Department of Water Resources (DWR) long-term contracts will continue (or be replaced by DWR or utility bilateral contracts) in 2005 and beyond.

Six others assume that "phantom congestion" will continue to impede the efficient use of existing Path 15 capacity in 2005 and beyond in the same manner that it did in 2000. While these six scenarios may overstate the impacts of phantom congestion, they provide useful insight into the potential ratepayer benefits of mitigating attempts by market participants to create artificial congestion on this and other transmission paths and otherwise game the market. Enron, and other market participants have engaged in strategies to create false congestion in the past, such as Enron's infamous "Death Star" scheduling system. Absent other actions to preclude such behavior in the future, the Path 15 project should help mitigate the impact of such strategies.

The ISO's remaining analyses include three scenarios where annual project benefits exceed project costs. However, these scenarios assume one-in-ten year drought year conditions or relatively pessimistic forecasts concerning new generation development north of Path 15, or both. Overall, the negative net benefits accumulated in the average hydro years are far greater than the positive net benefits accumulated in the drought years. Put another way, for every five years of average hydro conditions, you would need eight years of drought conditions for the project to break even.

We do not consider these to be likely conditions in 2005 and beyond. Moreover, as discussed above, these results were produced by a modeling effort that, in our view, lacks convincing validation and contains the upward biases described in this decision. Based on the record, we conclude that the ISO's market power study does not produce reliable or reasonable estimates of economic benefits with which to assess the Path 15 upgrades. Even if we could rely on the estimates produced by this study, the results indicate that the costs of the project would not even catch up with estimated benefits within a ten-year period, except under implausible scenarios.

As discussed in this decision, we believe that the ISO's analysis of Path 15 economic benefits should have acknowledged that various market power mitigation strategies are currently in place and/or will be in place between now and 2005, and *then* measured the effect of Path 15 upgrades on mitigating any residual market power costs. The closest approximation in the record to what the results of such an approach would likely be is the ISO's study that assumes the wholesale market will be competitive by 2005.

Under this study, the annual benefits of the upgrade are less than costs in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation north of Path 15 are assumed. *In scenarios that assume average hydro conditions, the project costs exceed benefits by $47 million/year or more, regardless of the level of new generation assumed.* In fact, under four out of the ten scenarios, the Path 15 upgrade actually increases market prices overall, i.e., the benefits of the project are *negative* by approximately $2.5 to $7.5 million. This is because the addition of 1500 MW in Path 15 transfer capacity increases market prices south of Path 15 more than it decreases market prices north of Path 15.

The two scenarios where annual benefits are greater than costs assume one-in-ten year drought conditions and relatively low levels of new generation north of Path 15. Even if we believed that the low new generation scenario is likely, the project would not be a cost effective investment to ratepayers unless there are a greater number of years with drought conditions in the future than there are years with average hydro conditions.

Based on record in this proceeding, including the project costs presented by PG&E in its testimony, we find that the proposed upgrades to Path 15 are not cost-effective to ratepayers. In a second phase of this proceeding held in late 2002, PG&E submitted updated project cost estimates and agreements among participants regarding the allocation of project costs and benefits. Those participants are: PG&E, Western Area Power Administration (WAPA) and Trans-Elect, Inc. (Trans-Elect). These issues were briefed in late September 2002. However, that information did not appear to change the project economics significantly.

2. Procedural Background

By ruling dated March 29, 2001, the Assigned Commissioner directed PG&E to file a Certificate of Public Convenience and Necessity (CPCN) to upgrade the portion of Path 15 between Los Banos and Gates substations. On April 13, 2001, PG&E submitted CPCN Application (A.) 01-04-012, as directed. A prehearing conference (PHC) was held on May 10, 2001 and another on June 27, 2001 to address scheduling issues for A.01-04-012. Public participation hearings were held on September 19, 2001 in Los Banos and Coalinga.

PG&E and the ISO served opening testimony on September 25, 2001. PG&E's testimony focused on more fully describing the project and the expected costs to build the project. The ISO testimony addressed the economic need for the project. The Office of Ratepayer Advocates (ORA) submitted testimony criticizing the ISO's economic analysis on November 8, 2001. ISO responded with rebuttal testimony on November 15, 2001. Evidentiary hearings were scheduled to begin on November 26, 2001.

Before the testimony could be subject to evidentiary hearings, PG&E filed a motion to withdraw A.01-04-012.[6] In its motion, PG&E stated that it would not build a stand alone Path 15 project in light of a recent agreement among various public and private entities to participate in a Path 15 expansion project, i.e., the

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[6] On November 6, 2001, PG&E filed a "Notice of Withdrawal" of A.01-04-012. The Commission Docket Office accepted the filing as a "Motion to Withdraw."

October 16, 2001 Memorandum of Understanding (MOU) executed by WAPA, PG&E, PG&E National Energy Group, Kinder Morgan, Transmission Agency of Northern California (TANC), Trans-Elect, and Williams Energy Marketing and Trading Company. The document provides a general discussion of the planned Path 15 expansion project, and leaves to future agreements the definition of parties' shares of the project costs and benefits, as well as specific roles and responsibilities. The MOU states that such agreements are to be executed no later than 90 days after the MOU was executed (i.e., by January 14, 2002).

ORA and ISO filed responses to PG&E's motion on November 13, 2001. By ruling dated November 30, 2001, the Assigned Commissioner denied PG&E's motion and consolidated A.01-04-012 with the Commission's generic investigation of transmission constraints, stating:

> "I.00-11-001 provides a logical forum to further explore the issue of project economics and to examine the allocation of benefits among project participants under the MOU development approach or a PG&E stand-alone project…. PG&E is currently a respondent to I.00-11-001 and matters surrounding the economics of transmission projects throughout the state are the subject of the investigation. Parties to A.01-04-012 should be prepared to discuss a schedule for supplemental testimony regarding the allocation of costs and benefits of the federal project at the December 19, 2001 prehearing conference already scheduled in I.00-11-001…. [T]he assigned Administrative Law Judge in I.00-11-001 will establish the scope and schedule for further consideration of the Path 15 expansion application, previously served testimony and supplemental testimony."[7]

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[7] Assigned Commissioner's Ruling in I.00-11-001/A.01-04-012, November 30, 2001, p. 5.

A further PHC was held on December 19, 2001, followed by the assigned ALJ ruling regarding the schedule and scope of evidentiary hearings.[8] The ISO filed Errata to the September 25 testimony on January 25, 2002, and ORA filed additional rebuttal testimony on February 8, 2002. Three days of evidentiary hearings were held on February 25, 26 and 27. During these hearings, the ALJ requested additional information from the ISO regarding the assumptions and methodology used to perform the economic analysis. This information was examined during a fourth day of evidentiary hearings on March 27, 2002.

Opening briefs were filed on April 10, 2002 by PG&E, ORA and ISO. ORA and the ISO filed reply briefs on April 22, 2002.

On April 30, 2002, WAPA filed a letter agreement at the Federal Energy Regulatory Commission (FERC) describing who will own the land, the lines and the transmission rights on the Path 15 upgrade and seeking pre-approval of a proposed ratemaking treatment for the project participants. Those project participants are identified as WAPA, PG&E and Trans-Elect. The letter agreement states that subsequent implementation agreements will provide more detail on the ownership percentages, project scope, and the nature of the ownership rights and responsibilities, including payments for project costs.[9]

It bears repeating that any private entity that owns or controls the electric transmission facilities that will be constructed pursuant to the certificate we authorize today is an electric corporation under California law. Pub. Util. Code

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[8] Assigned Administrative Law Judge's Ruling Regarding Hearings on the Path 15 Expansion Project, December 28, 2001.

[9] Path 15 Upgrade Project Participant's Letter Agreement, executed April 25, 2001, filed with FERC on April 30, 2002; Section 9. A copy of this document is attached as Attachment 3.

§ 218. If such an entity provides transmission service to others for compensation, it is a public utility subject to the jurisdiction of the Commission. Pub. Util. Code § 216(b). If it sells rights to transmission service to entities who resell the transmission service or resell electric energy "directly or indirectly, mediately or immediately … to the public or any portion thereof…" it is likewise a public utility. Pub. Util. Code § 216(c). PG&E is a utility regulated by this commission. Pursuant to the business arrangements described in the Letter Agreement filed by PG&E, Transelect and WAPA, Transelect is also a public utility "…subject to the jurisdiction, control, and regulation of the commission and the provisions of this part….." if those business arrangements go into effect.[10]

Supplemental hearings on the economics of the line were required by the ALJ and held in July 2002. Briefs and reply briefs on the supplemental issues were submitted in September 2002.

3. Issues and Scope

The scope of this proceeding focuses on an economic justification for the project, because the proponents, and all other parties, have disclaimed any improvement in reliability. More specifically, we examine the economics of the project on a "stand alone" basis—i.e., without considering the manner in which PG&E and other entities will participate in the project. During the course of this proceeding, PG&E stated that the MOU participants are still negotiating issues that may alter the project scope and overall costs. Therefore, we consider the cost figures presented in PG&E's opening testimony (which were also used in the economic analysis presented in the ISO's testimony) as placeholders.

[10] C.f., Unocal California Pipeline v. Conway, 23 Cal. App. 4th 331 (1994).

As discussed above, we have held additional evidentiary hearings to examine the implications of the participants' agreements and proposed ratemaking on our stand-alone evaluation. We do not find that this additional information changes the project economics significantly.

4. Project Description

Path 15 is a transmission interface located in the southern portion of PG&E's service area that is in the middle of the ISO control area. (See Figure 1.) It is comprised of two 500 kilovolt (kV), four 230 kV and several 70 kV lines and stretches for approximately 90 miles between the Los Banos and Gates substations in the San Joaquin Valley. The majority of the flow of power from southern California to northern California and to the Pacific Northwest flows through Path 15; the remaining small percentage (loop flow) goes through Arizona, Nevada, Utah and Idaho. Path 15 currently has the capacity to transfer 3950 MW from south to north on its existing lines. It is currently constrained to a lower transfer limit than the rest of the 500 kV system in northern California because there are just two 500 kV lines in this area.

Historically, during periods of low hydroelectric generation availability, PG&E draws on resources from southern California to meet customer demand in its service territory. At certain times, and due to a number of factors, the transfer capability of Path 15 between the zone south of Path 15 (SP15) and the zone north of Path 15 (NP15) reaches its limit before all available electrical resources can be moved between the zones. Congestion occurs, causing power shortages, increased prices, or both in the PG&E control area. During the later part of 2000, congestion on this path began to occur more frequently. The problem escalated further in the first part of 2001 as a shortage of generation in Northern California and reduced imports from the Northwest led to two days of rotating outages of firm customer load and numerous days of threatened outages.

In its application, PG&E identifies the following plan of service to upgrade Path 15:[11]

- Construct an uncompensated, single circuit 500 kV transmission line between Los Banos and Gates substations.
- Convert the Gates 500 kV bus from a ring bus arrangement to a breaker-and-a-half arrangement.
- Install 250 MVAR of 500 kV of shunt capacitors at both Gates and Los Banos
- Upgrade the Gates-Midway 230 kV line by either reconductoring portions of this line or by applying a temperature adjusted rating.

We refer to this plan of service as the Path 15 "upgrades" or "the project" throughout this decision. The project would add 1500 MW of power transfer capability to Path 15, increasing the total capability to approximately 5400 MW. In its application, PG&E projects that construction could be completed by summer 2004, if the CPCN were approved by early 2002.

5. Estimated Project Costs

PG&E estimates the cost of Path 15 upgrades along its preferred route at $323.1 million, including reconductoring of the Gates-Midway 230 kV line.[12] The annual revenue requirement associated with this cost would be between $48 million and $58 million / year depending on what factor (15% to 18%) is used to levelize costs. For the purpose of this decision, we use $50 million / year as an approximate cost against which to measure the annual forecasted benefits of the project. This is the figure that both ORA and ISO considered reasonable to use in

[11] PG&E's power system study that evaluated this plan of service, along with alternatives, is described in Exhibit (Exh.) 214, Section 6.

[12] Exh. 214, Section 6, p. 11.

this proceeding to calculate net project benefits. As discussed above, we view this cost projection as a placeholder during this phase of the proceeding.

6. ISO's Economic Analysis

The ISO conducted two studies estimating the economic impacts of Path 15 upgrades for a single year, 2005. The year 2005 was chosen because it was the first full year that the project was assumed fully operational. The first study, entitled "Path 15 Expansion Economic Benefit Study: Phase II--Year 2005 Prospect," presents an economic assessment of the value of the project assuming a competitive market.[13] The second study, entitled "Potential Economic Benefits to California Load From Expanding Path 15—Year 2005 Prospect," presents an economic assessment of the value of the project in the year 2005 as a risk mitigation measure to minimize the exercise of market power.[14]

In each of these studies, the ISO performed model runs to examine the impact of existing transmission contracts (ETCs) on project benefits. ETCs are existing transmission rights that predate ISO operations. Before describing the ISO study methods, input assumptions and results below, we first present a brief overview of how the ISO describes ETCs and their scheduling impact on Path 15 transmission capacity.

6.1 ETCs and the Problem of Phantom Congestion

There was extensive testimony and cross-examination in this proceeding on the problem of "phantom" or "paper" congestion caused by ETCs. ETCs are currently held by the California Department of Water Resources (CDWR), Transmission Agency of Northern California, Turlock Irrigation District, Los

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[13] Exh. 201, pp. 4-8; Attachment 3.

[14] *Ibid.*, pp. 8-11; Attachment 4.

Angeles Department of Water and Power (LADWP) and Pacificorp. As of March 31, 2002, the maximum contract capacity under ETCs totaled 2022 MW.[15]

The ISO witnesses describe the problem of phantom congestion as follows: FERC has required the ISO to honor all ETCs.[16] Many ETCs give their holders scheduling rights up to 20 minutes (or less) prior to transaction times:

> "As a result, the transmission capacity associated with ETCs is unavailable to Market Participants until 20 minutes or less prior to transaction time. Since all other Market Participants must submit Hour-Ahead Schedules to the CA ISO two hours prior to the hour in which a transaction occurs, Market Participants cannot utilize any ETC capacity that may become available 20 minutes prior to the hour. While FERC has on several occasions asked questions about its policy of honoring ETCs, to date it has maintained the policy."[17]

ISO Witnesses Greenleaf and Casey explained during hearings in more detail how they view the impact of ETCs on day-ahead and hour-ahead scheduling on Path 15.[18] Under ISO tariffs, this scheduling process begins with submittals by PG&E and Southern California Edison (SCE) for day-ahead total capacity reservations on Path 15 as well as specific schedules (hour-by-hour flows) for each ETC holder across Path 15. These day-ahead reservations and

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[15] RT at 852-861; Exh. 222.

[16] FERC Reports, ¶ 61,122; Order Conditionally Authorizing Limited Operation of an Independent System Operator and Power Exchange, issued October 30, 1997, Section III. Existing Contracts.

[17] Exh. 200, p. 9.

[18] See RT at 637-646; Exh. 200, pp. 9-10.

schedules must be made by 10:00 a.m. the day prior to the date of usage.[19] The ISO then subtracts the total amount of ETC reserved capacity from the MWs of available transmission capacity that the ISO can offer to other market participants ("new firm users") for scheduling in the day-ahead market.

Even though the ETC schedules submitted by PG&E and SCE in the day-ahead market have historically added up to far less MWs than the amount of total capacity reserved, the ISO holds the full capacity reservations until at least the hour-ahead market.[20] In that market (which closes two hours prior to the operating hour), ETC holders can further revise their day-ahead schedules up to the full capacity reservation amounts. In addition, most of the ETC holders have existing contract rights to schedule up to 20 minutes (or less) prior to the hour, and ISO Witness Casey testified that most of the ETC capacity reservations are actually held up to that time.[21] As a result, in practice, the ISO withholds from the day-ahead and hour-ahead markets the full amount of ETC capacity reservations, regardless of what amounts are actually scheduled in those markets. Whatever capacity is not used by 20 minutes before the hour becomes available for dispatch in real time. By that time, however, other market participants have lost their ability to submit additional schedules.

As a result, once the day-ahead reservations by ETC holders are locked in, the full amount of reserved capacity is lost to the system, even if it is ultimately not all used by the ETC holder. In this manner, the amount of ETC contract

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[19] PG&E manages the submittals on behalf of CDWR, TANC and Turlock; SCE manages the submittals on behalf of LADWP and Pacificorp.

[20] Exhs 223, 227; RT at 895-903.

[21] RT at 736-737, 867.

capacity that has been reserved in the day-ahead and hour-ahead markets, but not ultimately used, creates "phantom" or "paper" congestion.

In the studies discussed below, the ISO assumed that ETC holders in 2005 will reserve the same amount of capacity on Path 15 that ETC holders reserved in 2000.[22] Under the "exclude ETC" scenarios, the ISO assumes that none of the unused reserved capacity in the day-ahead or hour-ahead markets would be released, i.e., that all of it would remain unavailable to other transmission users, even if it were not utilized by ETC holders. Under the "include ETC" scenarios, the ISO assumes that all of the unused reservation capacity would be released so that other users could schedule that capacity.

6.2 Path 15 Economic Assessment Assuming Competitive Market

For this study, the ISO modeled the economic dispatch of a cost-based, transmission constrained system, similar to the methods used by the ISO in its congestion management activities. The ISO obtained the majority of the model input assumptions from the California Energy Commission (CEC), including loads, imports, fuel prices, unit operating characteristics and plant retirements.

The ISO refers to zones NP15, ZP26 and SP15 in its various scenarios: NP15 as being the zone north of Path 15; ZP26 and SP15 as being the zones south of Path 15. Since Path 15 connects ZP26/SP15 to NP15, the flow on this path is impacted by the amounts of new generation on either side.

The key assumption of this study is that market power is not being exercised. No single supplier has the ability to manipulate prices and each supplier bids its actual marginal costs. Under this assumption, the model

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[22] RT at 889, 951.

simulates cost-based bidding based on incremental heat rates, forecasted fuel prices (for the gas-fired generators) and variable operation and maintenance costs. During hours of congestion over Path 15, market clearing prices will reflect the higher costs of less efficient resources that need to be dispatched from alternate locations. By reducing congestion on Path 15, the project allows for a more efficient dispatch of generation resources, thereby lowering the market clearing price and producing project benefits.

The ISO used a load forecast based on year 2000 actual load with the CEC providing load growth factors through 2005. Three scenarios were used for new internal generation:

- A NP15 low scenario, in which a lower percentage of generation is built in NP15 and more in ZP26/SP15. For NP15, this includes the 4300 MWs projects already approved by the CEC plus 291 MW of peaker capacity.
- A medium or average scenario, where the same percentages of total capacity in NP15 and ZP26/SP15 are assumed to be built. For NP15, this includes 4300 MWs of projects approved by the CEC, 2800 MWs of projects pending approval, plus 291 MW of peaker capacity.
- A NP15 high scenario in which a larger percentage is built in NP15 as compared to ZP26/SP15. For NP15, this includes the new generation projects assumed in the medium scenario plus another 2,382 MWs of "announced" new projects (press release only).

The ISO also assumed that new generation external to the ISO control area in the northwest and southwest would also be built by 2005, and obtained data on projected new generation from the CEC. The ISO then applied the same proportions applied to new internal generation numbers to develop three new external generation scenarios: an average scenario, an NP15 low scenario and an

NP 15 high scenario. For example, the NP15 low scenario assumes a low level of new capacity in NP15 and in the Pacific Northwest.

The ISO ran all each of the new generation scenarios assuming average hydro conditions (in 2000) and assuming one-in-ten year drought conditions (64 percent of 2000). In addition, the ISO performed three additional hydro sensitivities with the low NP15 generation cases. These sensitivity cases modeled three hydro conditions that fall between the average hydro year and the one-in-ten drought year assumptions. In addition, the ISO performed a sensitivity case on the low NP15/dry hydro scenario to examine the impact of retaining ("exclude") or releasing ("include") unused ETC capacity on project benefits.

For each hour and each different scenario, the ISO produced one simulation with the Path 15 rating unchanged (the status quo case) and one simulation with the rating at the value determined with the additional 500 kV line. The ISO calculated the difference between economic indicators under the status quo and new rating cases to determine the net economic benefits of the project. In particular, the ISO examined the differences in "energy cost to load" and "re-dispatch costs." Energy cost to load looks at changes in the market-clearing price due to reduced congestion on Path 15. Re-dispatch costs looks at the way plants are dispatched to meet load—i.e., where along their production supply curves they produce power. Changes in re-dispatch costs are relatively insignificant. The vast majority of benefits discussed below relate to changes in energy cost to load.

The results of the ISO's assessment are presented in Table 1. As indicated in that table, in four out of the ten scenarios, the annual benefits of the Path 15 upgrade in the year 2005 are *negative* by approximately $2.5 to $7.5 million, that is, the energy cost to load actually increases relative to the status quo. This is because the market prices in Zones ZP26/SP15 (south of Path 15) increase more than prices decrease in Zone NP15 (north of Path 15). As ISO Witness Casey explained:

> "When you have upgrades to Path 15, the price in the north becomes lower because you are less dependent on the higher cost of units north. But because southern units are supplying generation to the north, the price in the south goes up. So, the cost impact to the north is their costs go down because they are facing a lower price. The cost impact in the south is their costs go up because they are facing a higher price. When you net those two, depending on the relative change in prices and the magnitude of load in the north and south, you can get a negative or a positive number."[23]

In all the scenarios where either (1) average hydro year conditions or (2) medium or high new generation north of Path 15 are assumed, the annual benefits of the line are less than the cost. In the scenarios that assume average hydro conditions, the project costs exceed benefits by $47 million / year or more, regardless of the level of new generation assumed.

Project benefits show positive values in 2005 only under the scenarios that assume a low NP15 generation scenario. However, they are still less than the projected annual costs of the project for all but two scenarios. For example, the scenario that modeled hydro conditions half way between an average year and approximately a one in ten year drought shows a benefit of only $14 million in terms of cost to load and a benefit of only $2.4 million in terms of re-dispatch costs.

Projected annual benefits in year 2005 are greater than the annualized cost of the project ($50 million) if one assumes one in ten year drought conditions and low NP15 generation development. The sensitivity case excluding all ETC

[23] RT at 659.

capacity (i.e., assuming that none of the unused capacity is released) shows a further increase in benefits in 2005.

6.3 Path 15 Economic Assessment Assuming Market Power

After completing the first study, the ISO filed a motion for extension of time in order to undertake an "assessment of market impacts that were not accounted for and reviewed in the initial work."[24] In this second study, the ISO examined the extent to which suppliers may be able to exercise market power in northern California (NP15) in the year 2005 under various new generation and hydro condition scenarios. The ISO utilized the same supply scenarios used in the study described above, but added scenarios relating to 1) the availability of transmission capacity subject to ETCs and 2) the State's long-term power contracts. The ISO then assessed the extent to which market power is mitigated through the addition of the Path 15 upgrades.

This assessment involved five steps. First, the ISO compared actual market prices in 2000 (from October 1999 to November 2000) with a forecast of what competitive prices should have been, using the competitive pricing model described above. This results in an estimate of the "price-cost markup" or "Lerner Index" in each hour, based on 2000 data. More specifically, the ISO calculated the percent by which actual prices were above estimated marginal costs in 2000.

Second, the ISO measured the ability of suppliers to exercise market power in 2000 by calculating the Residual Supply Index (RSI). The RSI is a measure of market concentration—more specifically, of whether the largest seller in a

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[24] Status Report and Motion for Extension of Time of the California Independent System Operator Corporation, August 17, 2001, p. 3.

particular market is pivotal in the sense that total market demand could not be met absent that seller's supply. Mathematically, the RSI is the ratio of total supply minus the largest supplier, divided by total demand. An RSI value less than 100% would indicate that the largest supplier is pivotal and thus would have the ability to set the clearing price. As the ISO explained during hearings, it has data on the capacity of each individual supplier in the market. Using that information and data on actual demand and total supply during 2000, the ISO was able to calculate RSIs for each hour in 2000.[25]

Third, the ISO conducted a regression analysis using this 2000 data. Specifically, the ISO regressed the Lerner Index (price-cost markup) against the RSI and actual system loads in each hour. This regression established a statistical relationship with which the ISO estimated price-cost mark-ups in each hour, given hourly values for RSI and loads.

Fourth, the ISO calculated RSIs for every hour in 2005 with and without the proposed expansion of Path 15. Using the statistical relationship described above, the ISO estimated the resulting price-cost markups in each hour to produce the costs due to market abuse with and without the Path 15 upgrades. The total economic benefits for year 2005 are the sum of the differences in these costs (with and without the Path 15 upgrades) for all hours in 2005.

The ISO conducted this analysis for a total of 24 different modeling scenarios. Twelve scenarios looked at two hydro conditions (dry, normal), three projections for new generation in NP15 (low, medium, high), and two conditions (100% and 0%) regarding the release of unused ETC capacity on Path 15.

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[25] RT at 905-906.

The ISO then evaluated each of these 12 scenarios with and without the State's long-term power contracts. Prior to the DWR entering into long-term contracts in 2001, all power purchases for investor-owned utility ratepayers were obtained through a bidding process in the power exchange, or "spot" market. As ISO Witness Casey explained during evidentiary hearings, by entering into contracts (or "forward contracting"), rather than relying on the spot market, the State could mitigate the market abuses that were occurring:

> "…the key mitigation elements of forward contracting are both that it reduces the amount of demand that is exposed to the shorter term market, which is more susceptible to market power, and…it reduces the suppliers' incentive to exercise market power in the shorter term markets."[26]
>
> "…if a supplier has committed a significant amount of its capacity to long-term contracts…the benefit of submitting high prices or withholding capacity, the benefit for exercising market power, is diminished."[27]

Under the "with long-term contracts" scenario, the ISO subtracts from the total load the amount that is covered by the DWR's long-term contracts. Only the remaining load (also referred to as the "net-short position") is subject to the price-cost markups estimated through the RSI methodology. The "without long-term contracts" scenario assumes that DWR no longer holds the long-term power contracts it negotiated in 2001, and therefore all of the purchases in the market are subject to the price-cost markups estimated through the RSI methodology. As one would expect, the project benefits under the "without" scenarios are

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[26] RT at 770.

[27] RT at 603.

substantially higher than under the "with" scenario. This is because the price-cost markups will apply to a larger amount of load. Conversely, when market power is mitigated through other measures (e.g., long-term contracts), reducing congestion on Path 15 has less economic impact. The mitigation effects of long-term contracts are due to the fact that the load under the contract is removed from the spot market. Those effects are independent from the prices negotiated under the contract, and do not speak to the issue of whether or not those prices are reasonable.

The results are summarized in Table 2. A more detailed presentation of the study results is presented in Tables 3 and 4. In the scenarios assessed, the ISO estimates that the potential benefits to load in northern California (NP15) range from $12 million to $1.3 billion, depending upon the assumptions made about hydro conditions, the development of new generation, availability of transfer capability subject to ETCs, and whether the State continues to hold long-term power contracts in 2005. The benefits of the upgrade are highest under a combination of one or more of the following assumptions for the year 2005: (1) no unused ETC capacity is released ("exclude ETC") (2) a low build-out of generation in NP15 ("low new generation"), (3) the State no longer holds long-term contracts with suppliers ("exclude long-term contract"), and/or (4) one-in-ten drought year conditions ("dry hydro").

7. Position of the Parties

PG&E presents no independent position concerning the economic benefits or cost-effectiveness of the Path 15 upgrades in this proceeding, stating that "…the ISO has undertaken to demonstrate that a Path 15 transmission capacity upgrade is needed to promote economic efficiency. PG&E, therefore, defers to the ISO's assessment of such economic benefit."[28]

In the ISO's view, the record strongly supports proceeding with the Path 15 upgrade.[29] By reducing the ability of suppliers to exercise market power, the ISO argues that the upgrade would "easily pay for itself within one drought hydro year and three normal years, and would in fact pay for itself within four normal years, even applying a 25% plus or minus factor."[30] Moreover, the ISO contends that the upgrade provides a cost-effective hedge against significant consumer harm in less likely, but still plausible worst-case scenarios.

More generally, the ISO views the Path 15 upgrades as part of a larger vision of transmission "backbone" of 500 kV transmission lines crossing the state:

> "In particular, the CA ISO has begun developing a vision of an adequate 500 kV backbone transmission system for the state. Several key projects have been identified and Path 15 has been determined to be one of the highest priority projects. There are also plans to increase the transmission capability between Southern California Edison Company and PG&E transmission systems on Path 26, and to increase transmission capability between the San Diego area and the rest of the state."[31]

According to the ISO, it is the lack of this type of backbone transmission that gives rise to the exercise of market power and the need for broad market-

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[28] PG&E Opening Brief, pp. 1-2.

[29] Our understanding from the record in this proceeding is that the ISO staff has taken a position, but not yet the ISO Governing Board, regarding the economic need of the project. (See RT at 533.) Therefore, our reference to the position of the ISO refers only to the staff position, as reflected in their testimony and during evidentiary hearings.

[30] ISO Opening Brief, p. 34.

[31] Exh. 200, p. 9.

wide mitigation measures. Correcting this deficiency through transmission upgrades would, according to the ISO, be more prudent than relying on ongoing regulatory intervention.[32]

ORA, on the other hand, contends that the only way in which the Path 15 upgrade can be justified is to make extremely pessimistic forecasts for the future. In particular, ORA argues that "the Commission would have to perceive a high risk that the wholesale electric market in 2005 *and subsequent years* will be as unbridled as California experienced in the winter and spring of 1999/2000."[33] Moreover, ORA argues that the ISO's market power modeling is seriously flawed. As an insurance policy, ORA contends that the investment in Path 15 upgrades requires a high premium ($50 million per year) for very limited coverage.[34] Finally, ORA argues that the MOU arrangements may or may not provide a better deal for ratepayers depending in large part on how Trans-Elect would operate its majority share of the project. In ORA's view, any final conclusions concerning project cost-effectiveness cannot be made without this further information.

8. Supplemental Economic Analysis

At the request of the ALJ, PG&E submitted additional testimony in July 2002 regarding the potential impact on project economics if the project is financed by parties other than PG&E as is currently proposed. PG&E indicated that there would be little change to the project costs, asserting in particular that the cost of capital for the project (debt and equity costs) would be the same for PG&E as for

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[32] Exh. 202, p. 5.

[33] ORA Opening Brief, pp. 39-40.

[34] *Ibid*., p. 43.

any other company since it would be based on the risks of the project. PG&E's testimony indicated that there may be a small cost decrease if the project is built by other parties instead of PG&E due largely to a reduction in property taxes if WAPA is involved, since as a Federal agency, WAPA would not be required to pay property taxes.

ORA disputed PG&E's testimony, indicating that other sources of financing could result in much less expensive means of paying for this project. In particular, ORA cited as an example the savings that could occur if the California Power Authority (CPA) were to finance this project using 100% debt financing rather than a typical mix of debt and equity.

9. Discussion

Over 3300 hours of congestion, comprising nearly 40% of all hours of transmission congestion in California, occurred in the south-north direction of Path 15 during 2000.[35] We initiated this phase of the proceeding to carefully evaluate the apparent transmission bottleneck on this transmission path.

All parties agree that the existing capacity of Path 15 (3950 MWs) meets system reliability criteria, as defined by the ISO, the Western Systems Coordinating Council and the North American Electric Reliability Council. Therefore, increasing the line capacity to approximately 5400 MWs is not needed for system reliability purposes. The issues we address today relate to the *economic need* for the project, i.e., whether adding 1500 MWs of capacity to the path produces cost savings to ratepayers that more than offset the project costs.

What is clear from the record in this proceeding is that the ISO's economic assessment of Path 15 upgrades *hinges on the presumption that the market abuses*

[35] D.01-03-077, Attachment 1, Table 5.

experienced in 2000 will persist in the industry in 2005 and beyond. In fact, the ISO estimates that the exploitation of market power by suppliers could cost ratepayers hundreds of millions of dollars in 2005 (and each year thereafter), even if Path 15 were built.[36] As discussed above, the ISO believes that transmission upgrades should be the first line of attack on such abuses.

We concur with ORA that this presumption is flawed. The ISO fails to recognize that the fundamental purpose of regulation is to ensure that players in the market *do not* exercise market power and harm customers. The players in the market have changed, but not this purpose. Prior to the deregulation of generation, regulation focused on preventing investor-owned utilities from garnering "monopoly profits" due to their unique position in the electric power market. This was accomplished by cost-of-service ratemaking and other regulatory methods that allowed only reasonable and prudent costs of generation to be recovered in rates, including a reasonable rate of return on capital investment. In other words, the price paid by ratepayers for generation was based on production costs, not on the ability of a utility to manipulate prices above costs in the market.

Deregulation of generation does not, and should not, change this focus. Nonetheless, there is clear evidence on the record that the players in the deregulated generation market not only exerted market power in 2000, resulting in prices to ratepayers that were far from cost-based, but continue to do so today.

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[36] See Tables 3 and 4 under the "costs due to exercising marketing power" rows at the top of each scenario. As one example, in Table 4 (including long-term contracts) under the dry hydro year, excluding ETC and medium generation scenario, the ISO estimates that ratepayers will continue to pay market power costs on the order of $205 million in 2005 ($611.41 million Path 15 status quo less $406.90 Path 15 expansion) even if the project is built.

As Figure 2, attached, illustrates, ratepayers have paid substantial price-cost markups for electric power (ranging from 10% to nearly 90%) in 2001. In its March 26, 2002 submittal to FERC, the ISO conducted an analysis of the bidding of individual suppliers through February 2002, and concludes that a significant amount of capacity is consistently being bid well in excess of marginal costs.[37]

What this signals to us is a *failure to regulate wholesale market players effectively*, rather than a failure to build transmission infrastructure. Market abuses by suppliers with a large share of the electric market simply should not be tolerated or presumed inevitable--and yet, the ISO's analytical framework does just that: It identifies suppliers that can exert market power, assumes that they cannot be thwarted in establishing high price-cost markups by any other means than constructing more transmission, and uses the resulting market-abuse baseline to evaluate the Path 15 transmission upgrade. This is not only a "worse case" planning scenario, it is an *unacceptable* scenario, in our view.

In fact, upon questioning by the ALJ, ISO Witness Casey acknowledged that London Economics, the ISO consultant that is developing a generic methodology for the economic assessment of transmission lines, has considered the impact of contract coverage (e.g., DWR or utility bilateral contracts with suppliers) and demand-responsiveness (e.g., real-time prices) on the economic need for transmission upgrades. Witness Casey testified that the consultant found there was *not* a significant amount of market power in the baseline (without the upgrade) when *either* of these types of mitigation measures is put in

[37] Exh. 228, Third Quarterly Report of the California Independent System Operator Corporation, March 26, 2002, pp. 39-52.

place. As a result, adding transmission capacity provides little benefit.[38] Moreover, forward contracting and demand-responsiveness are not the only strategies for addressing market power. The ISO's model indicates that market power is directly proportional to the largest generation owner's market share; therefore, divestiture is another regulatory tool that may be appropriate and, in fact, is the remedy currently sought by the Attorney General in lawsuits before the United States District Court.[39]

However, the ISO did not even try to compare construction of Path 15 upgrades to other market power mitigation strategies or explore the benefit-cost of such alternatives. Moreover, the ISO analysis does not acknowledge the initiatives already put in place since 2000 by this Commission and other state agencies to increase demand-responsiveness or to address market power and transmission congestion through distributed generation.[40] Nor did the ISO attempt to project the impact of such initiatives on market clearing prices in 2005.[41] Instead, by sequencing the assessment Path 15 upgrades as the first and

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[38] RT at 604-606. The generic methodology being developed by London Economics will be subject to evidentiary hearings at the Commission this fall. See, Administrative Law Judge's Ruling dated May 22, 2002 in this proceeding.

[39] Case No. C-02-1787, People of the State of California v. Mirant, Case No. C-02-1788, People of the State of California v. Reliant, April 15, 2002.

[40] Current efforts and plans to develop more extensive demand-responsiveness programs over the next 18 months are discussed in our June 10, 2002 Order Instituting Rulemaking on policies and procedures for advanced metering, demand response and dynamic pricing. (R.02-06-001.) The Commission's distributed generation initiatives are described in D.01-03-073 in R.98-07-037.

[41] The ISO's analysis simply assumes that the level of price-responsiveness in 2005 and beyond will be the same as it was in 2000. (RT at 777.) ISO Witness Casey testified that the ISO's programs had "limited success in 2001", but acknowledged that he was not an

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only market abuse mitigation measure, the ISO produced an analysis that fundamentally biases the results in favor of project construction.

The ISO's approach to estimating the impact of market power on prices also contains a modeling omission that further biases the results in favor of the project. The omission relates to forward contracting which, as discussed above, mitigates market power (i.e., lowers price-cost markups). As explained in Section 6.3 above**,** the ISO did take forward contracting into account in one sense: The ISO conducted scenarios that estimated the impact of DWR's forward contracting on project benefits by subtracting from the total load the amount of load that is covered by the DWR's long-term contracts. Only the load remaining was subject to the price-cost markups (Lerner Index) estimated through the ISO's regression analysis.

However, the *ISO's study ignores forward contracting in the underlying calculations* of *RSI values and the Lerner Index*. That is, the ISO did not consider the extent to which suppliers' capacity was pre-sold under forward contracts (either DWR contracts or with other entities outside of California) when it developed RSI values or used them in the regression analysis to estimate the price-cost markups. This omission was discovered during evidentiary hearings when the ALJ directed the ISO to assess how well its model tracked actual price-cost markups in 2001. In presenting this assessment, the ISO acknowledged that forward contracting was "an important factor that was not considered:"[42]

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expert in the programs or their impacts, and was not familiar with the details of the Commission's or CEC's programs. (RT at 702-705.)

[42] RT at 910.

> "Forward contracts for significant amounts of power were signed after January 2001. However, in the 2001 analysis, we did not incorporate forward contracting into our analysis. In theory, a higher level of forward contracting at predetermined prices should result in less market power (i.e., lower price-cost markups). The model used in the CA ISO's market power study does not explicitly consider the portion of each supplier's capacity that is presold under forward contracts…. *The fact that the parameter was not added for the 2001 simulation may be a further reason why the model tends to over predict price-cost markups in the Summer of 2001*…. A more detailed 2001 RSI analysis would only include the proportion of supply with which suppliers could bid strategically."[43]

The impact of rectifying this omission cannot be quantified without researching the forward contracting position of all suppliers in 2001, recalculating the RSI's in each hour and redoing the regression analysis. However, ISO Witness Casey acknowledged during cross-examination that, on an intuitive basis, the direction of the bias would be to "overestimate the market power impact" of the project.[44] This is consistent with the ISO's observation that the omission of this parameter in the model could be a further reason why the model over predicts the actual price-cost markups in 2001.[45]

The validation assessment required by the ALJ further documents this upward bias and, more generally, illustrates the predictive weakness of the ISO's market power model. Figure 2 presents a comparison of the price-cost mark-ups predicted by the ISO's model and actual price-cost markups for 2001. As indicated in that figure, the ISO model fails to reasonably predict actual price-cost

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[43] Exh. 221, p. 6. (emphasis added.)

[44] RT at 916-917.

[45] Exh. 221, p. 6.

markups throughout that period, and most noticeably overestimates the price-cost markups from May through September when more long-term contracts are in place. The ISO also submitted a comparison of simulated and actual price-cost markups for the period from November 1998 to October 1999, because the ISO believes that this earlier period represents a "more normal year relative to 2001", for which its model would be a better predictor.[46] (See Figure 3.) However, even though the ISO model closely tracks the price-cost markups over some of this period, it significantly overestimates the price-cost markups in November and December of 1998 and June, July, August and September of 1999.

In fact, the only validation of the model conducted by the ISO prior to the ALJ's request was to examine the "t-statistics" for variable coefficients and the "R-squared" for the regressions that were used to estimate the Lerner Index (price-cost markups). Upon further questioning during evidentiary hearings, it became clear that the regressions used to estimate the Lerner Index in the off-peak season (November 1999 through April 2000), for both peak and off-peak hours do not meet the ISO's criteria for statistical significance. In particular, ISO Witness Casey testified that an R-squared of 0.5, which means that 50 percent of the variation in the Lerner Index is explained by the variations in RSI and actual system loads, is considered "pretty good" for time series data.[47] In addition, he testified that a statistic should be 2.00 or greater in order to be confident that the relationship observed between the Lerner Index and RSIs or actual loads are meaningful (i.e., the coefficients are statistically greater than zero).[48] However,

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[46] RT at 943.

[47] RT at 935-936.

[48] *Id.*

the R-squared statistics for Off-Peak Season Peak-Hours and Off-Peak Season Off-Peak Hours are only 0.42 and 0.34, respectively. Moreover, the t-statistic for actual loads during Off-Peak Season Peak Hours is only 0.80.[49] In other words, the regression results do not meet the ISO's own criteria for statistical validation during six months out of the year.

Finally, even if the sequencing bias, modeling omission and lack of confidence in the ISO's model were not of concern, we could not overlook the fact that the ISO's assessment of market power impacts includes scenarios that are simply implausible. As indicated in Table 2, the ISO conducted 24 different scenarios in it market power study. Twelve of those scenarios assume that *none* of the DWR long-term contracts will continue in 2005 (and therefore all load will be met in 2005 through spot market transactions exposed to price-cost markups). This one assumption has a major impact on the level of benefits derived from ISO's market power study. (See Table 2.) However, during questioning by the ALJ, ISO Witness Casey acknowledged that the continuation of DWR contracts was one of the assumptions that the ISO considered "reasonable" in evaluating the project.[50] In fact, none of the evidence suggests that a scenario that assumes the disappearance of all long-term contracts in 2005 and beyond is even plausible. Even if the existing DWR contracts were to be completely voided by the FERC, we expect that DWR or the utilities under Commission order would enter into new forward contracts to prevent overexposure in the spot market. In Rulemaking (R.) 01-10-024, we are will be examining the role of forward

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[49] Exh. 201, p. 15.

[50] RT at 591. Exh. 200, p. 7.

contracting, along with other utility procurement strategies, in addressing the State's net-short position.

For the above reasons, we agree with ORA that the twelve scenarios that exclude long-term contracts should not be considered further.

That leaves twelve scenarios remaining, six of which assume that ETC "phantom congestion" will continue to impede the efficient use of existing Path 15. The ISO estimates that between 1145 and 1250 hours of congestion on Path 15 in the south-north direction *could have been avoided* in 2000 had unused ETC capacity been available.[51] On average, in 2000, only 30.6% of the ETC capacity reserved in the day-ahead market was ever actually scheduled by ETC holders. For the hour-ahead market, only 38.3% of the amount reserved was scheduled.[52] All of the ISO's "exclude ETC" scenarios assume that this inefficient use of the existing 3950 MW of Path 15 transmission capacity will continue in 2005 and beyond. We note that this assumption has a major impact on the ISO's estimate of economic benefits under the market power study. In particular, the "exclude ETC" scenario *increases* the ISO's estimate of economic benefits in 2005 by $143 million, under drought year conditions, and by $73 million, under normal hydro conditions.[53]

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[51] Exh. 200, p. 10; RT at 647-648.

[52] Exh. 229. To understand these average annual percentage results, an example for a single hour is useful. Suppose that the day-ahead amount reserved in hour 12 pm to 1 pm on 1/1/2000 is 608 MWs. Now suppose that in the day-ahead scheduling process, the amount of ETC scheduled in this same hour is 186 MW. The percentage of ETC scheduled to the ETC reservation is 186/608 = 30.6%.

[53] RT at 551-552; These figures are based on the ISO's estimate of economic benefits using "the plausible assumption that at least one drought hydro year can be assumed, that there will be a medium build out of new generation in northern California, and that the State's long term energy contracts remain in effect." Exh. 200, p. 7. We note that,

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We do not consider the results of these scenarios to be accurate, for several reasons. First, the ISO's method for trying to capture the impact of ETCs on the economics of the project appears to inflate the estimated benefits in all of the "exclude ETC" scenarios. As discussed above, ETCs cause phantom congestion on the line to the extent that the ETC holder does not schedule (use) the full amount of its day-ahead capacity reservation. However, rather than simply subtracting the day-ahead unscheduled ETC from operational transmission capacity in these scenarios, the ISO subtracts the full amount of ETC capacity reserved in 2000, which is more than two times the amount of the unscheduled ETC capacity in that year.[54] We fail to see the rationale for this approach. The amount of capacity that an ETC holder reserves and schedules in the day-ahead market would not impact the potential for market power on Path 15 any more than would the amount of capacity that a new firm user schedules in that market.

Second, even if it were appropriate to subtract the full ETC reservation amount from operational transmission capacity, the evidence on the record persuades us that this amount will be significantly reduced in the years 2005 and beyond. This is because the following ETC holdings completely terminate between 2004 and 2008: 300 MWs out of the 1110 MWs held by CDWR, all of LADWP and Pacificorp holdings (580 MW) plus the 32 MWs held by Turlock

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since the filing of written testimony and evidentiary hearings, the ISO has modified somewhat the assumptions it considers plausible. (ISO Opening Brief, pp. 33-34.) Nonetheless, we must rely on the evidence submitted in sworn testimony in characterizing the ISO's position in this case, and do so in assessing the impacts of the "exclude ETC" scenarios on that position.

[54] Exhs. 227, 229.

Irrigation District.[55] It is unreasonable to assume that the amount of reserved capacity in 2005 and beyond will stay the same as in 2000 when over 45% of the contract capacity will no longer be subject to ETCs.

Finally, we must consider the underlying assumption of the "exclude ETC" scenarios, i.e., that the inefficiencies and resulting costs to ratepayers caused by phantom congestion will be allowed to persist without regulatory intervention. We note that this issue is squarely before the FERC in three dockets. In California Independent System Operator Corp., Docket No. ER00-2019, the market inefficiency caused by phantom congestion has been identified and is being addressed in overall settlement negotiations.[56] The issue is also before FERC in Docket No. EL01-47-000, in which the ISO has submitted two options to resolve phantom congestion.[57] In addition, the problem of phantom congestion is before FERC in Docket No. EL01-89-000, a complaint filed by Morgan Stanley Capital Group (MSCG) against the ISO. In its September 28, 2001 order setting the complaint for hearing, FERC states:

> "As a preliminary matter, we disagree with the ISO that MSCG should have filed its complaint against PG&E and Edison rather than the ISO. The ISO, itself, has stated that "phantom congestion" is a problem because a significant portion of the ISO Controlled Grid Capacity is encumbered under Existing Contracts [ETCs] with non-participating Transmission Owners and that the scheduling timelines under certain of these Existing Contracts are at odds with the ISO scheduling process defined in

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[55] RT at 853-854.

[56] See California Independent System Operator Corp., 91 FERC ¶ 61,205 at 61,727 (2000) (recognizing "phantom congestion" as a market inefficiency, and establishing settlement procedures concerning proposed Amendment No. 27 to ISO Tariff).

[57] Exh. 220, Attachment 6, p. 4.

> the ISO tariff and the Scheduling Protocol. Thus, MSCG's complaint seeking interim relief to "phantom congestion" is appropriately filed against the ISO, since the ISO, not PG&E or Edison controls the transmission grid capacity and the scheduling process under its tariff.
>
> "…Therefore, we will institute an investigation on the complaint. The hearing should determine whether there are reasonable interim solutions available that would remedy this problem of "phantom congestion" for transmission users of the ISO grid absent a total market redesign. We recognize that ultimately the regional market in the West must be operated under standard scheduling procedures that will apply to all market participants."[58]

However, we have yet to see significant, coherent measures implemented by FERC and/or the ISO to eliminate the ability or financial incentives for market participants to actively game the system. After more than two years, FERC has yet to order refunds of the high costs that were charged to ratepayers in 2000 and 2001 or find that generators inappropriately abused their market power. For these reasons, we find the six scenarios in ISO's market power study that "exclude ETCs" have merit in demonstrating the potential costs to ratepayers of continued reliance on a FERC-regulated wholesale market to provide significant portions of the electricity used in California, and the potential negative impacts to ratepayers of abuses of that market by energy traders and generation companies.

In the six scenarios that remain, the ISO estimates that only three of them produce benefits that exceed the estimated annual project cost of $50 million. These three scenarios assume one-in-ten year drought conditions, low generation

[58] *Ibid.*, pp. 5-6. FERC has held hearings in abeyance pending settlement discussions, which are continuing at this time. RT at 851-852.

development in northern California and the Pacific Northwest, or both. (See Table 2.) Overall, the negative net benefits accumulated in the average hydro years are far greater than the positive net benefits accumulated in the drought years. *Put another way, for every five years of average hydro conditions, California would need eight years of drought conditions for the project to break even*.[59] We do not consider these to be "likely" conditions in 2005 and beyond. Moreover, these results were produced by a modeling effort that, in our view, lacks convincing validation and biases the project benefits upwards.

Based on the record, we conclude that the ISO's market power study does not produce reliable or reasonable estimates of economic benefits with which to assess the Path 15 upgrades. Even if we could rely on the estimates produced by this study, the results indicate that the costs of the project would not even catch up with estimated benefits within a ten-year period, except under implausible scenarios, with the exception of the potential for, and the history of, rampant gaming by market participants.

As discussed above, the ISO fundamentally errs in its market power assessment by putting arguably the most expensive fix—construction of a $323 million transmission project—as the *first* step in mitigating the market abuses experienced in 2000. This approach not only presumes that regulators will fail to take any other action to address market power abuses or transmission congestion in the future, but it also ignores the initiatives that have been put in place by this Commission and other agencies since 2000 to address these issues, such as forward contracting, demand-responsiveness programs, and incentives for distributed generation. This sequence results in inflated project benefits

[59] Exh. 217, p. 8; RT at 832-834.

because those benefits are measured when market power is at its maximum. Instead, as ORA observes, the ISO should have acknowledged that various market power mitigation strategies are currently in place and/or will be in place between now and 2005, and *then* measured the effect of Path 15 upgrades on mitigating any residual market power costs.[60] The closest approximation in the record to what the results of such an approach would likely be is the ISO's study that assumes the wholesale market will be competitive by 2005.

As indicated in Table 1, in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation in NP15 are assumed, the annual benefits of the upgrade are less than the costs. In the scenarios that assume average hydro conditions, *annual project costs exceed benefits by $47 million per year or more*, regardless of the level of new generation assumed. The only scenarios for which annual project benefits are greater than costs are the last two scenarios. Both assume one-in-ten year drought conditions and low new generation build-out in northern California and the Pacific Northwest. One of these scenarios excludes all ETC capacity. Even if we believed the low new generation assumption to be likely, the project would not a cost-effective investment for ratepayers unless there are a greater number of years with drought conditions in the future than there are years with average hydro conditions.

Based on these results, we conclude the project is not cost-effective assuming normal operation of the market. This conclusion is based on the assumption that Path 15 upgrades will cost a total of $323 million (approximately $50 million per year on an annualized basis). However, given the potential for

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[60] ORA Opening Brief, p. 12.

future abuses of the market by FERC-regulated generators, and the uncertainty that FERC and the ISO can or will take sufficient action to mitigate such market abuses, we conclude that the Path 15 upgrades may provide benefits by mitigating, at least in part, efforts by market participants to cause phantom congestion, unreasonably drive up market prices and even potentially cause shortages of power and blackouts in Northern California.

We do not agree with PG&E's assertion that it makes little difference which entity finances and builds this project. PG&E's assertion that the cost of capital is unrelated to the underlying company's financial situation, but instead rests solely on the economics of the specific project is incorrect. As PG&E itself has pointed out, PG&E's current financial status results in a higher cost of debt for PG&E and may restrict PG&E's ability to even obtain financing for this project. It is clear that the financial community is as concerned with the financial status of the company in addition to the specific costs and revenues of an individual project.

We also find compelling ORA's example that other means of financing, particularly use of all debt financing via the CPA or other means could result in a significant reduction in the annual costs to ratepayers for this project. While alternative sources of financing may be of value, as ORA has indicated, the record in this proceeding is insufficient to determine if such alternatives are available at this time.

10. Comments on Proposed Decision

The alternate proposed decision of Commissioner Lynch in this matter was mailed to the parties in accordance with Public Utilities Code Section 311(d) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on ___________ and reply comments were filed on __________.

11. Assignment of Proceeding

Loretta Lynch is the Assigned Commissioner and Meg Gottstein is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Parties in this proceeding agree that the proposed Path 15 upgrades ("the project") are not needed for system reliability purposes, but disagree on whether there is an economic need for the project.

2. The assessment of economic need assumes that the project will cost a total of $323 million, or approximately $50 million per year on an annualized basis. This cost figure is a placeholder, pending finalization of project costs by PG&E.

3. The project is evaluated on a "stand-alone" basis in this proceeding, i.e., without considering the manner in which PG&E and other entities will participate in the project.

4. The ISO's assessment of the economic benefits associated with the project hinges on the presumption that the market abuses experienced in 2000 will persist in the industry in 2005 and beyond. It identifies suppliers that can exert market power, assumes that they cannot be thwarted in establishing high price-cost markups by any other means than constructing more transmission, and uses the resulting market-abuse baseline to evaluate the project.

5. The ISO's consultant, London Economics, found that adding transmission capacity provides relatively little economic benefit to ratepayers when contract coverage and/or demand-responsiveness programs are put in place to mitigate market power.

6. The ISO's analysis ignores the initiatives that have been put in place by the Commission and other agencies since 2000 to address market power abuses and mitigate transmission congestion, such as forward contracting, demand-responsiveness programs and incentives for distributed generation. It also

presumes that regulators will fail to take any other actions to address market power abuses in the future.

7. By establishing the baseline for its market power study in the manner described above, the ISO's analysis results in inflated project benefits.

8. The ISO's market power study also ignores forward contracting in the underlying calculations of RSI values and the Lerner Index. This omission further biases the results in favor of project construction.

9. The validation assessment performed at the ALJ's request in this proceeding documents the upward bias of the ISO's modeling method and, more generally, illustrates its predictive weakness.

10. The regression results used by the ISO to predict price-cost markups in 2005 do not meet the ISO's own criteria for statistical validation during six months out of the year.

11. None of the evidence in this proceeding suggests that the disappearance of all forward contracting in 2005 and beyond is plausible. This assumption is used for 12 out of the 24 scenarios presented in the ISO's market power study.

12. Six of the remaining ISO scenarios ("exclude ETCs") assume that the inefficient use of ETCs in 2000 will continue in 2005 and beyond without regulatory intervention.

13. The method used by the ISO to try to capture the impact of continued ETC inefficiency on the economics of the project appears to inflate the estimated benefits in the six scenarios that exclude ETCs. This is because the ISO subtracts the full amount of ETC capacity reserved in 2000 from operational transmission capacity in these scenarios, rather than the amount of unscheduled ETC capacity.

14. Even if it were appropriate to subtract the full ETC reservation amount from operational transmission capacity, the evidence indicates that this amount

will be significantly reduced in the years 2005 and beyond because over 45% of the ETC contract capacity will expire between 2004 and 2008.

15. While inflated, the ISO's forecast of benefits when congestion occurs provides insight into the potential benefits to consumers of improving Path 15 should market participants be able to create false congestion in the future.

16. In the six scenarios that remain, the ISO estimates that only three of them produce benefits that exceed the estimated annual project cost of $50 million. These three scenarios assume one-in-ten year drought conditions, low generation development in northern California and the Pacific Northwest, or both. For every five years of average hydro conditions, California would need eight years of drought conditions for the project to break even.

17. The ISO's study based on competitive market prices is the closest approximation to a study that acknowledges the various market power mitigation strategies currently in place and those that will be in place between now and 2005.

18. Under the competitive market study, annual project costs *exceed* benefits by $47 million per year or more in all of the scenarios where either (1) average hydro year conditions or (2) medium or high new generation in northern California are assumed.

19. Under the competitive market study, annual project benefits are greater than costs in only two scenarios, where one-in-ten year drought conditions and low new generation build-out in northern California are assumed. One of these scenarios excludes all ETC capacity.

Conclusions of Law

1. The ISO's market power study does not produce reliable or reasonable estimates of economic benefits with which to assess the project. Even if we could rely on the estimates produced by this study, the results indicate that the benefits

of the project would not catch up with estimated costs within a ten-year period, except under implausible scenarios or if market gaming is rampant.

2. Under the ISO's study that assumes competitive market pricing, the project would not be a cost-effective investment for ratepayers unless we believe that (1) low new generation build-out for northern California and the Pacific Northwest is likely *and* (2) there will be a greater number of years with drought conditions in the future than years with average hydro conditions.

3. Based on the record in this proceeding, the proposed upgrades to Path 15 are not cost-effective to ratepayers on a stand-alone basis, except potentially as a means of mitigating market gaming.

INTERIM ORDER

IT IS ORDERED that Pacific Gas and Electric Company may proceed to construct this project on a stand-alone basis or in participation with other entities.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT 1

LIST OF APPEARANCES

ATTACHMENT 2

LIST OF ACRONYMS AND ABBREVIATIONS

ATTACHMENT 2

LIST OF ACRONYMS AND ABBREVIATIONS

A.	Application
ALJ	Administrative Law Judge
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPA	California Power Authority
CPCN	Certificate of Public Convenience
D.	Decision
DWR	Department of Water Resources
ETCs	existing transmission contracts
Exh.	Exhibit
FERC	Federal Energy Regulatory Commission
I.	Investigation
ISO	Independent System Operator
kV	kilovolt
LADWP	Los Angeles Department of Water and Power
MOU	Memorandum of Understanding
MSCG	Morgan Stanley Capital Group
MW	Megawatt
NP15	north of Path 15
ORA	Office of Ratepayer Advocates
PG&E	Pacific Gas and Electric Company
PHC	prehearing conference
Pub. Util. Code	Public Utilities Code
R.	Rulemaking
RSI	Residual Supply Index
RT	Reporter’s Transcript
SCE	Southern California Edison
SP15	South of Path 15 zone
TANC	Transmission Agency of Northern California
Trans-Elect	Trans-Elect, Inc.
WAPA	Western Area Power Administration
ZP26	Zone south of Path 15, but north of Path 26

(END OF ATTACHMENT 2)

ATTACHMENT 3

LETTER AGREEMENT

LIST OF TABLES AND FIGURES

TABLE 1

TABLE 1: ISO's Competitive Market Study ISO COMPETITIVE MARKET STUDY							
(Annual Benefits, Levelized Costs and Net Benefits)							
	SCENARIO ASSUMPTIONS						
Hydro	**ETC**		**New gen.**	**Re-dispatch benefits ($ million)**	**Load cost benefits ($ million)**	**Costs ($ million)**	**Annual Net ($ million)**
Dry	Include	-	High	$ 0.51	-$ 7.47	$50.00	-$56.96
Dry	Include	-	Medium	$ 1.14	-$ 7.43	$50.00	-$56.29
Normal	Include	-	High	$ 0.33	-$ 2.86	$50.00	-$52.53
Normal	Include	-	Medium	$ 0.44	-$ 2.44	$50.00	-$52.00
Normal	Include	-	Low	$ 0.93	$ 2.09	$50.00	-$46.98
Sensitivity 3	Include	-	Low	$ 1.35	$ 4.10	$50.00	-$44.55
Sensitivity 2	Include	-	Low	$ 2.41	$ 14.01	$50.00	-$33.58
Sensitivity 1	Include	-	Low	$ 4.60	$ 41.70	$50.00	-$3.70
Dry	Include	-	Low	$ 9.02	$ 83.05	$50.00	$42.07
Dry	Exclude	-	Low	$16.42	$118.55	$50.00	$84.97

TABLE 2

TABLE 2: ISO MARKET POWER STUDY (Annual Benefits, Levelized Costs and Net Benefits)						
	SCENARIO ASSUMPTIONS:					
Hydro	**ETC**	**Long-term contract**	**New gen.**	**Benefits ($ million)**	**Costs ($ million)**	**Annual Net ($ million)**
Normal	Include	Include	High	$11.65	$50.00	-$38.35
Normal	Include	Exclude	High	$16.32	$50.00	-$33.68
Dry	Include	Include	High	$24.20	$50.00	-$25.80
Normal	Include	Include	Medium	$31.19	$50.00	-$18.81
Dry	Include	Exclude	High	$33.43	$50.00	-$16.57
Normal	Include	Exclude	Medium	$48.36	$50.00	-$1.64
Normal	Exclude	Include	High	$50.37	$50.00	$0.37
Dry	Include	Include	Medium	$61.75	$50.00	$11.75
Normal	Include	Include	Low	$68.78	$50.00	$18.78
Normal	Exclude	Exclude	High	$74.61	$50.00	$24.61
Dry	Include	Exclude	Medium	$91.05	$50.00	$41.05
Dry	Exclude	Include	High	$94.87	$50.00	$44.87
Normal	Exclude	Include	Medium	$104.11	$50.00	$54.11
Normal	Include	Exclude	Low	$108.71	$50.00	$58.71
Dry	Exclude	Exclude	High	$136.64	$50.00	$86.64
Normal	Exclude	Exclude	Medium	$161.66	$50.00	$111.66
Dry	Include	Include	Low	$189.31	$50.00	$139.31
Dry	Exclude	Include	Medium	$205.37	$50.00	$155.37
Normal	Exclude	Include	Low	$208.70	$50.00	$158.70
Dry	Include	Exclude	Low	$289.19	$50.00	$239.19
Dry	Exclude	Exclude	Medium	$305.08	$50.00	$255.08
Normal	Exclude	Exclude	Low	$325.35	$50.00	$275.35
Dry	Exclude	Include	Low	$841.71	$50.00	$791.71
Dry	Exclude	Exclude	Low	$1,304.07	$50.00	$1,254.07
Source: Exh. 201, Attachment 4						

TABLE 3

Table 3: Summary Results of Estimated Cost Savings to NP15 Load from Path 15 Expansion (Excluding Long-term Contracts)[1]

		Normal Hydro Year (Year 2000) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$494.41	$938.23	$213.42	$124.93	$297.52	$39.15
	B: Path 15 Expansion	$325.11	$613.84	$131.08	$74.86	$189.54	$21.07
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$169.31	$324.39	$82.34	$50.08	$107.97	$18.08
Benefit from Price reduction (C1)		$0.42	$26.33	($0.01)	$0.05	$4.14	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$168.89	$298.06	$82.35	$50.03	$103.83	$18.08
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$4.14	$17.48	$2.71	$1.61	$6.65	$0.94
Total Cost Benefit to NP15 Load (C+D)		$173.45	$341.87	$85.05	$51.68	$114.62	$19.02
E: Cost Impact to SP15 Load		-$11.79	-$16.52	-$10.45	-$3.32	-$5.91	-$2.70
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$161.66	$325.35	$74.61	$48.36	$108.71	$16.32
		Bad Hydro Year (64% of Year 2000 hydro volume) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$927.14	$2,231.94	$408.65	$245.74	$598.98	$83.37
	B: Path 15 Expansion	$613.88	$1,178.93	$261.82	$151.26	$360.24	$46.68
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$313.26	$1,053.01	$146.83	$94.48	$238.74	$36.69
Benefit from Price reduction (C1)		$5.37	$479.95	$0.01	$1.02	$51.55	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$307.89	$573.06	$146.82	$93.46	$187.19	$36.69
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$7.34	$278.69	$1.23	$2.95	$68.24	$0.59
Total Cost Benefit to NP15 Load (C+D)		$320.60	$1,331.70	$148.06	$97.43	$306.97	$37.28
E: Cost Impact to SP15 Load		-$15.52	-$27.63	-$11.42	-$6.39	-$17.79	-$3.85
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$305.08	$1,304.07	$136.64	$91.05	$289.19	$33.43

[1] Source: Exh. 201, Attachment 4, p. 19.

TABLE 4
Table 4: Summary Results of Estimated Cost Savings to NP15 Load from Path 15 Expansion (Including Long-term Contracts)[2]

		Normal Hydro Year (Year 2000) $MM					
		Exluding ETC			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$311.23	$589.12	$136.48	$79.89	$185.72	$26.23
	B: Path 15 Expansion	$206.33	$386.13	$85.15	$48.64	$118.99	$14.44
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$104.90	$202.98	$51.33	$31.25	$66.73	$11.79
Benefit from Price reduction (C1)		$0.26	$19.18	($0.01)	$0.04	$3.14	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$104.64	$183.81	$51.34	$31.21	$63.60	$11.79
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$1.05	$9.67	$0.37	$0.41	$3.61	$0.11
Total Cost Benefit to NP15 Load (C+D)		$105.95	$212.65	$51.70	$31.65	$70.34	$11.90
E: Cost Impact to SP15 Load		-$1.85	-$3.96	-$1.33	-$0.46	-$1.56	-$0.25
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$104.11	$208.70	$50.37	$31.19	$68.78	$11.65
		Bad Hydro Year (64% of Year 2000 hydro volume) $MM					
		Exluding ETC [a]			Including ETC		
Proposed New Generation Scenarios		Medium	Low	High	Medium	Low	High
Costs Due to Excercising Marketing Power	A: Path 15 Status Quo	$611.41	$1,454.07	$271.42	$163.13	$389.29	$57.24
	B: Path 15 Expansion	$406.90	$775.71	$175.53	$101.51	$235.03	$32.75
C: Cost Savings to NP15 Load from Reduced Market Power from Path 15 Expansion (A-B)		$204.52	$678.36	$95.89	$61.62	$154.25	$24.49
Benefit from Price reduction (C1)		$3.65	$308.30	$0.00	$0.79	$33.38	$0.00
Benefit rom Reduction in Price-Cost Markup (C2)		$200.86	$370.06	$95.89	$60.84	$120.87	$24.49
D: Costs Savings due to Lower Competitive Prices form Path 15 Expansion		$3.94	$171.85	$0.44	$1.49	$41.28	$0.20
Total Cost Benefit to NP15 Load (C+D)		$208.46	$850.21	$96.34	$63.12	$195.53	$24.68
E: Cost Impact to SP15 Load		-$3.09	-$8.50	-$1.46	-$1.37	-$6.22	-$0.48
Net Cost Benefit to NP15 & SP15 Load (C+D+E)		$205.37	$841.71	$94.87	$61.75	$189.31	$24.20

[2] Source: Exh. 201, p. 20.

FIGURE 1

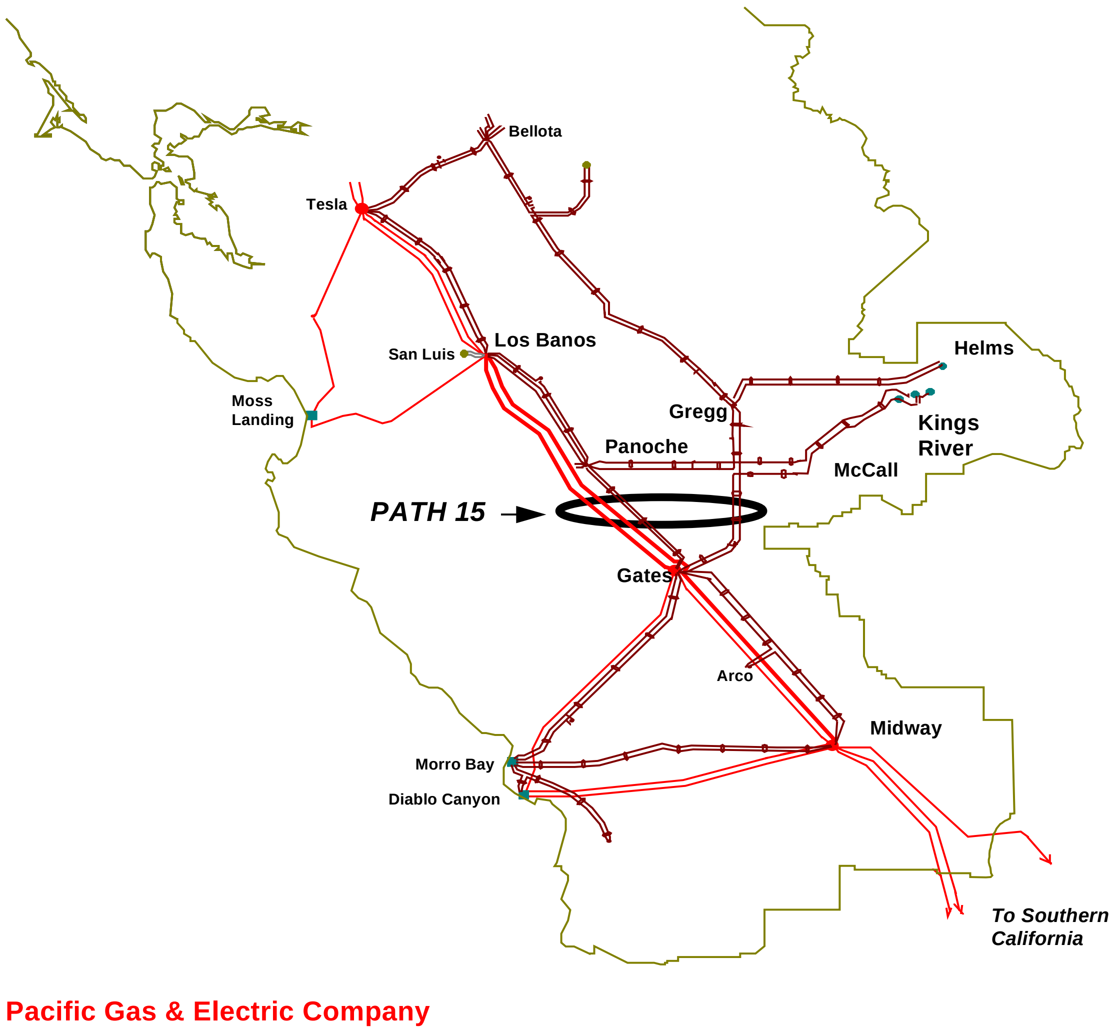
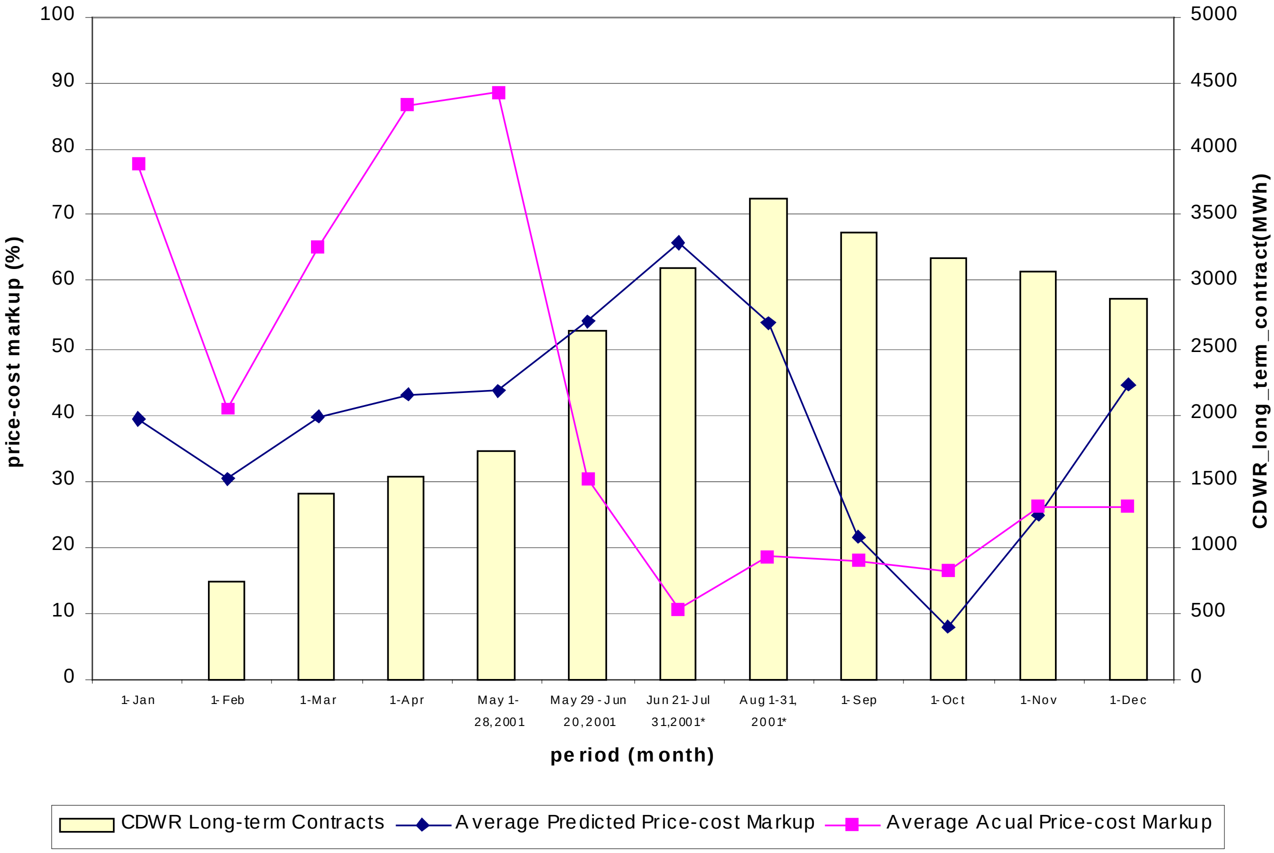


Figure 1: Path 15

Source: Exh. 201, Attachment 3, Figure 2.1

FIGURE 2

Figure 2. Comparison of Average Simulated Price-cost Markups and Average Actual Price-cost Markups (2001)[1]



[1] For the simulation in 2001, a simple average of the CA ISO's real-time incremental prices and regional hub prices is used as a measure of daily spot market energy prices. The regional hub price is computed as an average of COB and Palo Verde prices and is computed for peak and off-peak hours separately. SOURCE: Exh. 221, p. 4.

FIGURE 3

Figure 3. Comparison of the Simulated Price-cost Markups and Actual Price-cost Markups (November 1, 1998 to October 31, 1999)[2]

[2] For the simulation from November 1998 to October 1999, the regional energy price is computed as the weighted average of real-time price and the CA PX price. The weights are real-time INC volume and CA PX transaction volume netting out the Utility Distribution Companies' own generation. SOURCE: Exh. 221, p. 7.